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March 17, 2022

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Long-Term Supply for Southern Labrador – Phase 1 - Supplemental Information

On July 16, 2021, Newfoundland and Labrador Hydro ("Hydro") submitted an application for the approval of construction of Phase 1 of Hydro's long-term supply plan for southern Labrador ("Application").[1] On November 10, 2021, Hydro requested a cessation in the review schedule on the Application to allow for continued stakeholder engagement and consultation to ensure the greatest possible alignment and understanding among all parties.[2] Hydro provided the Board of Commissioners of Public Utilities ("Board") and parties with a further update on stakeholder consultations on January 31, 2022, and requested that the Board resume the review schedule to allow the consideration of the Application to continue.[3]

In February 2022, discussions were held between Newfoundland Power Inc. ("Newfoundland Power") and Hydro regarding additional alternatives for reliable power supply to the southern Labrador region. On this basis, Hydro performed additional technical and economic analyses of the alternatives suggested by Newfoundland Power. The objective of these analyses was to assess technical viability and to compare lifecycle costs to those of the alternatives presented previously as part of Hydro's Long-Term Supply Study for Charlottetown: Economical & Technical Assessment.[4]

The first suggested alternative involved immediate interconnection of all four communities in southern Labrador without construction of the regional diesel generating station. The second alternative suggested was to interconnect all four communities in southern Labrador, similar to Alternative 5: Interconnection with Hydro Generation proposed by Hydro in its Application,[5] but delay the construction of the regional diesel generating station until the scheduled replacement of the diesel generating station in Mary's Harbour in 2030. Under this scenario, the Charlottetown Diesel Generating Station would not be constructed as proposed. Rather, the three existing diesel generating stations located in Port Hope Simpson, Mary's Harbour, and St. Lewis would provide firm capacity to all four communities until 2030.

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[1] "Long-Term Supply for Southern Labrador – Phase 1," July 16, 2021, Newfoundland and Labrador Hydro.
[2] "Long-Term Supply for Southern Labrador – Phase 1," November 10, 2021, Newfoundland and Labrador Hydro.
[3] "Long-Term Supply for Southern Labrador – Phase 1 – Stakeholder Consultations – Further Update," January 31, 2022, Newfoundland and Labrador Hydro.
[4] "Long-Term Supply for Southern Labrador – Phase 1," July 16, 2021, Newfoundland and Labrador Hydro, sch. 1, att. 1.
[5] "Long-Term Supply for Southern Labrador – Phase 1," July 16, 2021, Newfoundland and Labrador Hydro, sch. 1, s. 4.6, at p.8.

Detailed analyses completed by Hydro in response to Newfoundland Power's suggested alternatives can be found in the technical notes included as Attachments 1 and 2.[6]

As indicated in these technical notes, there are benefits to Newfoundland Power's suggested alternatives, such as reduced up-front capital cost and the deferral of the construction of a new diesel generating station. However, Hydro's analyses indicate that its original recommendation for phased interconnection of the southern Labrador communities and construction of a regional diesel generating station remains the least-cost alternative.

Further to previous queries on actions to further reduce greenhouse gas emissions, Hydro is advancing a number of initiatives to decrease potential emissions from the proposed facility. Outcomes from the consultation process in recent months include Hydro's commitment to work with the Nunacor Development Corporation to support the development of sustainable energy solutions for their communities. In addition, Hydro has begun the exploration of the application of biofuels in its remote systems. Biofuels, such as a biodiesel mix, could potentially be an alternative to the current diesel fuel consumed by Hydro's diesel generating units.

As a first step, Hydro confirms that the design of the proposed regional diesel generating station in Port Hope Simpson can be provisioned for biofuel use. Hydro would therefore have the flexibility to add required systems, such as additional filtering, without requiring major modifications. Hydro is committed to understanding the cost and operational considerations associated with biofuel applications and will submit a report to the Board with its findings at the end of 2022. This study will include a review of supply alternatives, an assessment of operational impacts on equipment, and an exploration of the national experience with biofuels for off-grid use.

In summary, Hydro has confirmed that the solution proposed within its Application would meet the immediate reliability needs of its customers, would have the lowest lifecycle cost, and would be adaptable to future system requirements in its ability to accommodate load growth and economic development in the region. In addition, the proposed solution provides significant flexibility in its ability to displace fuel and carbon emissions through integration with renewable generation and through the potential application of biofuels.

In consideration of these findings, Hydro requests the Board resume the schedule to allow for the continuation of the Application review.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/sk

Encl.

[6] Technical notes "RP-TN-051: Southern Labrador – Interconnection without Regional Diesel Plant" (Attachment 1) and "RP-TN-054: "Southern Labrador – Full Interconnection – Delayed Regional Diesel Plant" (Attachment 2).

ecc:

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Attachment 1

Technical Note RP-TN-051: Southern Labrador – Interconnection without Regional Diesel Plant

Doc #: RP-TN-0511
Issue Date: 2022/01/2415
Document Type: Technical Note

RP-TN-051

Southern Labrador - Interconnection Without Regional Diesel Plant

1 Purpose

The purpose of this study is to evaluate an additional alternative to supply reliable power to the southern Labrador region in comparison to those already evaluated as part of Hydro's Long-Term Supply Study for Charlottetown: Economic & Technical Assessment ("Long-Term Supply Study"). Assumptions throughout this study are deliberately applied to favour the suggested alternative, as a stress test.

The suggested alternative, referenced as "Alternative 6," is to interconnect all four communities without constructing a centralized diesel plant and not replacing the Charlottetown diesel plant. Instead, relying on the existing diesel plants to provide firm capacity to the region. This alternative would be similar to Alternative 3b (Full Interconnection of Southern Labrador).[1]

2 Diesel Plant Capacity

2.1 Existing System

The diesel generation facilities are the primary sources of power for each of the communities included in the southern Labrador proposal. These facilities are made up of a combination of fixed diesel gensets installed inside engine halls and mobile gensets, which are self-contained units installed outside the diesel plant building. Mobile gensets have a number of disadvantages[2] compared to fixed genets and their roles are limited because of these disadvantages.

In Charlottetown, the existing diesel generating facility is comprised of only mobile gensets and is considered a temporary configuration until a long-term supply solution is implemented in the region. In Mary's Harbour, there is one mobile genset installed to supply the summer peak load of the community, but it is not considered in firm capacity during the winter.

The capacity of the existing diesel units and diesel plants in the southern Labrador region are provided in Table 1. Mobile gensets are indicated with an "(M)"

[1] Additional details on alternatives can be found in the Long-Term Supply Study included as "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1.
[2] As outlined in "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, s. 3.2.

Table 1: Diesel Plant Capacities[3]

Ratings	Charlottetown[4]	Mary's Harbour	Port Hope Simpson[5]	St. Lewis
G1		545	545	200
G2		545	725	365
G3	910 (M)	725	455	455
G4	910 (M)	725 (M)		
G5	725 (M)			
Installed Capacity (kW)	2,545	2,540	1,725	1,020
Design Plant Capacity (kW)	N/A[6]	1,500	1,500	2,000
Firm Capacity – Summer (kW)	1,635	1,815	1,000	565
Firm Capacity – Winter (kW)	1,635	1,090	1,000	565

2.2 New Alternative

If the systems under consideration are connected as suggested and the existing generation is shared amongst the communities, only some of the existing generation would be part of the area's firm capacity.

The following assumptions were applied in determining the appropriate units to consider as part of the suggested systems firm capacity:

- The Charlottetown diesel plant would not be replaced and the mobile gensets would be removed, as they are only a temporary installation and therefore not considered in the suggested systems firm capacity for any time of the year;[7]
- The mobile genset in Mary's Harbour is included in the firm capacity for the summer only. It is not considered as part of the system's winter firm capacity;
- The suggested system will require N-2 redundancy
    - There are concerns that addition redundancy beyond N-2 may be required, given the large number of units overall (9-10 depending on the season).[8]

With these assumptions in place, the firm capacity of the region is as indicated in Table 2.

[3] As outlined in "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, Table 1, at p. 2, with individual unit capacities shown.
[4] This assumes the current arrangement with just mobile gensets.
[5] There is some potential to increase the Port Hope Simpson design capacity to 1,750 kW, but the original design was based on three 500 kW units.
[6] The design capacity in Charlottetown was 1,500 kW prior to the fire.
[7] If the Charlottetown mobile gensets are included in the area's summer capacity, but not winter, it has little impact on the results of this study as the winter season has the most firm capacity constraints.
[8] If the scope of the suggested alternative were to be fully developed, additional consideration and reliability analysis would have to occur before determining if additional redundancy beyond N-2 would be required. This assumption could be skewing this analysis in favor of the suggested alternative.

Table 2: System Capacities

Rating	Summer	Winter
Installed Capacity (kW)	5,285	4,560
Firm Capacity (kW)	3,835	3,110

3 Forecast and Firm Capacity Requirements

3.1 Forecast

The combination of the four communities under consideration will experience its peak load in the summer due to the large fish plant operations in Mary's Harbour and Charlottetown. However, it is also important to consider winter operation as the availability of certain gensets changes on a seasonal basis.

The forecasted peak load for the southern Labrador Region for the winter and summer is provided in Table 3.

Table 3: Southern Labrador Forecast[9]

Year	Summer Peak (kW)	Winter Peak (kW)
2025	3,613	2,963
2035	3,667	3,030

3.2 Remaining Available Capacity

By comparing the forecasted firm capacity requirements (Table 3) to the available firm generation capacity (Table 2), it can be concluded that Hydro would have enough capacity to meet the regional peak demand in both the summer and winter season with N-2 planning criteria.[10] The amount of available capacity in these scenarios is presented in Table 4.

Table 4: Suggested System - Remaining Excess Capacity

Year	Summer Peak (kW)	Winter Peak (kW)
2025	222	147
2035	168	80

[9] Based on Southern Labrador Interconnection – 50-Year Forecast August 2020.
[10] If the suggested alternative were to be fully developed, Hydro would have to assess if the remaining excess capacity as indicated is appropriate given that it could result in the need to delay future customers until additional generation could be added.

3.3 Maximum Firm Generating Capacity

The existing diesel plants in the communities under consideration are already operating at or near their design capacity except for St. Lewis. To increase the firm capacity, 545 kW units could be in Port Hope Simpson and St. Lewis to replace smaller units. In addition, there is a provision in St. Lewis to add a fourth 545 kW genset.

Table 5 shows the maximum firm capacity without increasing the total number of diesel gensets.

Table 5: Suggested System Maximum Capacity without Increasing Number of Units

Rating	**Summer (kW)**	**Winter (kW)**
Region Firm Capacity	5,990	5,265
Region Excess Firm Capacity (2025)	927	852
Region Excess Firm Capacity (2035)	873	785

To support incremental load growth beyond the capacities listed in Table 5, the additional unit could be installed in St. Lewis. Table 6 shows the maximum firm capacity with this addition.

Table 6: Suggested System Maximum Capacity with Increasing Number of Units

	Summer (kW)	**Winter (kW)**
Region Firm Capacity	6,535	5,810
Region Excess Firm Capacity (2025)	1,472	1,397
Region Excess Firm Capacity (2035)	1,418	1,330

It is noted that in this scenario, there would be very little excess firm capacity available for economic development in the region. For example, any advancement of mining activity with year-round demand in the area would likely increase capacity requirements to the point that a new diesel plant would likely be required.

4 Cost-Benefit Analysis Assumptions

An economic model of the suggested alternative is developed by modifying the existing alternatives already considered in Hydro's Long-Term Supply Study. This includes modelling the costs for the following:

- Major capital cost of diesel plant replacements;
- Operating maintenance cost (non-fuel);
- Reoccurring minor capital upgrade costs;
- Diesel plant replacements; and
- Fuel costs.

4.1 Major Capital Cost

The capital cost assumed for Alternative 6 is the same as the interconnection portion of Alternative 3B, approximately $34.5 million.[11] The additional cost of implementing a control system capable of managing the operation of the interconnected diesel plants was not included in the cost-benefit analysis.[12] There is no opportunity to develop the distribution interconnection in phases as specified in Alternative 3a since there is not enough generation in Port Hope Simpson to support the load in Charlottetown.

4.2 Operating Maintenance Costs (Non-Fuel)

The operating maintenance costs for Alternative 6 were assumed to be the same as Alternative 2 except all the costs associated with a new plant in Charlottetown are removed. The operating maintenance costs of the other three plants are reduced to 90% for all years of the analysis to account for the potential to reduce the total number of existing units from ten to nine.[13] No additional costs were included to account for the increased operation of the existing generating units.[14] The additional operating maintenance costs associated with the interconnection were also excluded from the analysis.[15]

4.3 Reoccurring Minor Capital Upgrades

The reoccurring minor capital costs for Alternative 6 were assumed to be the same as Alternative 2 except all the costs associated with a new plant in Charlottetown are removed. The reoccurring capital costs of the other three plants are reduced to 90% for all years of the analysis to account for the potential to reduce the total number of existing units from ten to nine.[16] No additional costs were included to account for the increased operation of the existing generating units.[17]

4.4 Diesel Plant Replacements

The timing and costs of diesel plant replacements were assumed to be the same as those applied in Alternative 2. A sensitivity analysis is included in Section 6 to determine the Cumulative Net Present Value ("CPW") of Alternative 6 if the diesel plant replacement costs were reduced to 50%. It is noted that maintaining a reliable level of service with such a significant reduction in sustaining capital would be

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[11] 54% of $63.9 million = $34.5 million as outlined in "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, Table 7, at p. 33 and Table 14, at p. 41.

[12] This assumption skews the analysis in favor of the suggested alternative as, the capital costs of this control system would be a relevant cost to consider if the suggested alternative was evaluated in detail.

[13] This assumption skews the analysis in favor of the suggested alternative as any operations and maintenance ("O&M") savings associated with a reduction in total number of diesel units would only be realized after other units below 455 kW were upgraded to 545 kW units.

[14] This assumption skews the analysis in favor of the suggested alternative as in reality there would be a significant increase in the number of operating hours on the diesel units in the three remaining diesel plants in comparison to Alternative 2. This would result in increased operation and maintenance costs at the remaining diesel plants.

[15] This assumption skews the analysis in favor of the suggested alternative as the O&M cost of the interconnection line would be a relevant cost to consider if the suggested alternative was evaluated in detail.

[16] This assumption skews the analysis in favor of the suggested alternative as any reduction in reoccurring capital costs associated with a reduction in the total number of diesel units would only be realized after other units below 455 kW were upgraded to 545 kW units.

[17] This assumption skews the analysis in favor of the suggested alternative as in reality there would be a significant increase in number of operating hours on the diesel units in the three remaining diesel plants in comparison to Alternative 2. This would result in increased reoccurring minor capital costs at the remaining diesel plants.

extremely challenging. For the purpose of this sensitivity investigation, it is assumed that only moderate plant refurbishment would be required for long-term operation.[18]

4.5 Fuel Costs

The fuel costs included in the economic model for Alternative 6 are calculated by assuming the diesel plant efficiency of Alternative 2,[19] the distribution system losses of Alternative 5,[20] and station service losses of Alternative 2 with the losses at Charlottetown removed. No additional station service losses are modelled at the remaining diesel plants even though the amount of generation from these plants is expected to increase.[21]

5 Cost-Benefit Analysis Results

5.1 Base Case Results

The results of the cost-benefit analysis with the suggested alternative modelled, as previously described, are provided in Table 7.

Table 7: CPW Analysis Results (2020–2070) – 50 Year Study ($)[22]

Alternative	CPW	CPW Difference between Alternative and the Least-Cost Alternative
Alternative 3a: Phased Interconnection	153,400,000	0
Alternative 3b: Full Interconnection	155,300,000	1,900,000
Alternative 6: Interconnection w/o Regional Diesel Plant	173,500,000	20,100,000
Alternative 1: Mobile Option	177,400,000	24,000,000
Alternative 2: New Charlottetown Plant	184,700,000	31,200,000

5.2 Sensitivity Analysis Results

5.2.1 Reduced Diesel Plant Replacement Costs

If the cost of diesel plant replacements is reduced to 50% for the suggested alternative only, then the results of the cost-benefit analysis are as provided in Table 8.

18 Based on recent major diesel plant refurbishment project costs (Makkovik), it is not expected that a major refurbishment would cost less than 50% of a diesel plant replacement.
19 The fuel efficiency for the generation of power consumed in Charlottetown is assumed to be the same as Alternative 2.
20 This assumption skews the analysis in favor of the suggested alternative as the system losses are expected to increase due to the of power flow from Mary's Harbour and St. Lewis to Charlottetown, which is a greater distance then from Port Hope Simpson to Charlottetown.
21 This assumption skews the analysis in favor of the suggested alternative as it is expected that the station service losses at the existing diesel plant would increase due to the increased amount of generation at these plants.
22 CPW is presented in 2020 dollars.

Table 8: CPW Analysis Results - Sensitivity Analysis (Reduced Diesel Plant Replacement Costs) ($)

Alternative	CPW	CPW Difference between Alternative and the Least-Cost Alternative
Alternative 3a: Phased Interconnection	153,400,000	0
Alternative 3b: Full Interconnection	155,300,000	1,900,000
Alternative 6: Interconnection w/o Regional Diesel Plant	158,200,000	4,800,000
Alternative 1: Mobile Option	177,400,000	24,000,000
Alternative 2: New Charlottetown Plant	184,700,000	31,200,000

6 Conclusion

Based on the contents of this technical note and the analysis presented, it is concluded that the suggested alternative, Alternative 6, is not the least-cost alternative when compared against the least-cost alternative already presented in Hydro's Long-Term Supply Study. This remains the case even if sustaining capital costs were reduced by over 50%.

Finally, the presented solution would not be able to accommodate appreciable economic development in the region until a regional diesel plant is developed. This is of particular importance when considering the mineral deposits in the area. As stated above, one would need to ensure an extremely low sustaining capital investment for the suggested alternative to be viable. Hydro has demonstrated such an approach would have significant risk, as there would be a requirement for major plant expansions to accommodate load growth.

In summary, Alternative 6 involves a solution that does not include the construction of a new diesel plant in southern Labrador. Through cost-benefit analysis, Hydro has demonstrated that such an approach would result in increased lifecycle costs for customers and would be prohibitive for appreciable near-term load development in the region. On this basis, Hydro recommends Alternative 3a as the preferred alternative.

Document Summary

Document Owner:	Rural Planning
Document Distribution:	

Revision History

Revision	Prepared by	Reason for change	Effective Date
1	S. Henderson	Initial Release	2022-02-01
2	S. Henderson	Editorial Changes (from Executive)	2022-02-03
3	S. Henderson	Minor Edits	2022-03-15

Document Control

Regarding Rural Planning documents: The electronic version of this document is the CONTROLLED version. Please check the Rural Planning Document Management System SharePoint site for the official copy of this document. This document, when downloaded or printed, becomes UNCONTROLLED.

Attachment 2

Technical Note RP-TN-054: Southern Labrador – Full Interconnection – Delayed Regional Plant

RP-TN-054

Southern Labrador - Full Interconnection - Delayed Regional Plant

1 Purpose

The purpose of this study is to evaluate an additional alternative to supply reliable power to the southern Labrador region in comparison to those already evaluated as part of Hydro's Long-Term Supply Study for Charlottetown: Economic & Technical Assessment ("Long-Term Supply Study")[1] and RP-TN-051 (Southern Labrador – Interconnection Without Regional Diesel Plant).

The alternative presented in this technical note was developed in consultation with Newfoundland Power, which has been reviewing system alternative configurations for the supply of southern Labrador. In response to these suggestions, further analysis was performed by Hydro to compare suggested solutions against those presented previously by Hydro.

This document will include a review of a solution proposed by Newfoundland Power, referenced as "Alternative 7."[2] Assumptions throughout this study are deliberately applied to favour the suggested alternative, as a stress test. A list of all the alternatives considered is provided in Table 1.

Table 1: Southern Labrador - List of Alternatives

Alternative #	Title	Source
1	Continued Operation of Mobile Gensets	Long-Term Supply Study
2	New Diesel Plant in Charlottetown	
3a	Southern Labrador Interconnection – Phased Approach	
3b	Southern Labrador Interconnection – Full Interconnection	
4	Interconnection to the Labrador Interconnected System	
5	Interconnection with Hydro Generation	
6	Southern Labrador – Interconnection Without Regional Diesel Plant	RP-TN-051
7	Southern Labrador – Full Interconnection – Delayed Regional Plant	Focus of this Study (RP-TN-054)

Alternative 7 would involve the interconnection of all four communities and delay the construction of the centralized diesel plant until the diesel plant in Mary's Harbour is scheduled to be replaced in 2030. Under

[1] "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1.

[2] A variation of the solution outlined in this document was assessed by Hydro based on another suggested system configuration provided by Newfoundland Power Inc. This solution is outlined in RP-TN-051 and is referenced as "Alternative 6." It was confirmed through economic analysis that Alternative 6 was found to be less cost effective than Alternative 7.

this scenario, the Charlottetown diesel plant will not be replaced, and instead, the existing diesel plants will be required to provide firm capacity to the region until 2030. Benefits of Alternative 7 include the delay of the requirement for a new diesel plant, which would reduce interest costs. However, this would be offset by inflation, increased fuel, and capital costs that would be required to meet forecasted demand and ensure system reliability until the regional diesel plant is constructed in 2030.

2 Diesel Plant Capacity

2.1 Existing System

The diesel generation facilities are the primary sources of power for each of the communities included in the southern Labrador proposal. These facilities are made up of a combination of fixed diesel gensets installed inside engine halls and mobile gensets, which are self-contained units installed outside the diesel plant building. Mobile gensets have a number of disadvantages[3] compared to fixed gensets and therefore their roles are limited.

In Charlottetown, the existing diesel generating facility is comprised of only mobile gensets and is considered a temporary configuration until a long-term supply solution is implemented in the region. In Mary's Harbour, there is one mobile genset installed to supply the summer peak load of the community, but it is not considered in firm capacity during the winter.

The capacity of the existing diesel units and diesel plants in the southern Labrador region are provided in Table 2. Mobile gensets are indicated with an "(M)"

Table 2: Diesel Plant Capacities[4]

Ratings	Charlottetown[5]	Mary's Harbour	Port Hope Simpson[6]	St. Lewis
G1		545	545	200
G2		545	725	365
G3	910 (M)	725	455	455
G4	910 (M)	725 (M)		
G5	725 (M)			
Installed Capacity (kW)	2,545	2,540	1,725	1,020
Design Plant Capacity (kW)	N/A[7]	1,500	1,500	2,000
Firm Capacity – Summer (kW)	1,635	1,815	1,000	565
Firm Capacity – Winter (kW)	1,635	1,090	1,000	565

[3] As outlined in "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, s. 3.2.
[4] From "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, Table 1, at p. 2, with individual unit capacities shown.
[5] This assumes the current arrangement with just mobile gensets.
[6] There is some potential to increase the Port Hope Simpson design capacity to 1,750 kW, but the original design was based on three 500 kW units.
[7] The design capacity in Charlottetown was 1,500 kW prior to the fire.

2.2 New Alternative

If the systems under consideration are connected as suggested and the existing generation is shared amongst the communities, only some of the existing generation would be part of the area's firm capacity. The following assumptions are applied in determining the appropriate units to consider as part of the suggested systems firm capacity:

- The Charlottetown Diesel plant would not be replaced and the mobile gensets would be removed, as they are only a temporary installation and therefore not considered in the suggested systems firm capacity for any time of the year;[8]
- The mobile genset in Mary's Harbour is included in the firm capacity for the summer only. It is not considered as part of the system's winter firm capacity; and
- Given the relatively large number of interconnected units in the proposed system configuration, it is recommended that N-2 redundancy be applied, at a minimum.[9]

With these assumptions in place, the firm capacity of the region is as indicated in Table 3

Table 3: System Capacities

Rating	Summer	Winter
Installed Capacity (kW)	5,285	4,560
Firm Capacity (kW)	3,835	3,110

3 Forecast and Firm Capacity Requirements

3.1 Forecast

The combination of the four communities under consideration will experience its peak load in the summer due to the large fish plant operations in Mary's Harbour and Charlottetown. However, it is also important to consider winter operation as the availability of certain gensets changes on a seasonal basis.

The forecasted peak load for the southern Labrador Region for the winter and summer is provided in Table 4.

Table 4: Southern Labrador Forecast[10]

Year	Summer Peak (kW)	Winter Peak (kW)
2025	3,613	2,963
2035	3,667	3,030

[8] If the Charlottetown mobile gensets are included in the area's summer capacity, but not winter, it has little impact on the results of this study as the winter season has the most firm capacity constraints.

[9] For the scope of the suggested alternative to be fully developed, additional consideration and reliability analysis would be required before determining if additional redundancy beyond N-2 is required. For the purposes of this investigation, N-2 redundancy is assumed to minimize costs for the suggested alternative.

[10] Based on Southern Labrador Interconnection – 50-Year Forecast August 2020.

3.2 Remaining Available Diesel Capacity

By comparing the forecasted firm capacity requirements (Table 3) to the available firm generation capacity (Table 2), it can be concluded that Hydro would have enough diesel capacity to meet the regional peak demand in both the summer and winter season with N-2 planning criteria.[11] The amount of available capacity in these scenarios is presented in Table 5.

Table 5: Suggested System - Remaining Excess Capacity

Year	Summer Peak (kW)	Winter Peak (kW)
2025	222	147
2035	168	80

3.3 Auxiliary Diesel Plant Capacity

In many of Hydro's isolated systems, plant auxiliary systems and conductors are sized to accommodate peak load as opposed to full plant output. As a result, upgrades may be required to fully utilize installed diesel plant capacities to meet increased load requirements. Alternative 7 is predicated on the notion of using full plant capacity to serve customer load. As a result, upgrades to the auxiliary equipment would be necessary. Tables 6, 7, and 8 list the auxiliary equipment upgrades that would be required for each existing plant.

Table 6: Mary's Harbour Diesel Plant – Capacity Constraints

Equipment	Equipment Size	Capacity Limitation	Required Capacity[12]	Upgrade Required (Y/N)
Service Conductor	4 x 777 MCM[13]	1,660 kW	1,787 kW	Y
Main Bus	1,400 A	1,310 kW	1,787 KW	Y
Substation Transformer	3 x 500 kVA	1,485 kW	1,787 KW	Y

[11] If the suggested alternative is to be fully developed Hydro would have to assess if the remaining excess capacity as indicated is appropriate given that it could result in the need to delay future customers until additional generation could be added.
[12] Installed capacity within diesel plant minus station service (28 kW in Mary's Harbour and Port Hope Simpson, 19 kW in St. Lewis).
[13] Million cubic metres ("MCM").

Table 7: Port Hope Simpson Diesel Plant – Capacity Constraints

Equipment	Equipment Size	Capacity Limitation	Required Capacity	Upgrade Required (Y/N)
Service Conductor	4 x 313 MCM	1,075 kW	1,697 kW	Y
Main Bus	1,200 A	1,122 kW	1,697 kW	Y
Substation Transformer	3 x333 kVA	989 kW	1,697 kW	Y

Table 8: St Lewis Diesel Plant – Capacity Constraints

Equipment	Equipment Size	Capacity Limitation	Required Capacity	Upgrade Required (Y/N)
Service Conductor	3 x 750 MCM	1,321 kW	1,001 kW	N
Main Bus	1,200 A	1,122 kW	1,001 kW	N
Substation Transformer	3 x 333 kW	989 kW	1,001 kW	Y

In summary, under the proposed arrangements, substantial upgrades would be required at all facilities to meet customer load requirements.

3.4 Maximum Firm Generating Capacity

The existing diesel plants in the communities in southern Labrador are already operating at or near their design capacity except for St. Lewis. To increase the firm capacity, 545 kW units could be in Port Hope Simpson and St. Lewis to replace smaller units. In addition, there is a provision in St. Lewis to add a fourth 545 kW genset.

Table 9 shows the maximum firm capacity without increasing the total number of diesel gensets.

Table 9: Suggested System Maximum Capacity without Increasing Number of Units

	Summer (kW)	Winter (kW)
Potential Firm Capacity	5,990	5,265
Potential Firm Capacity Buffer[14] (2025)	927	852
Potential Firm Capacity Buffer (2035)	873	785

To support incremental load growth beyond the capacities listed in Table 9, the additional unit could be installed in St. Lewis. Table 10 shows the maximum firm capacity with this addition.

[14] Firm capacity buffer is the difference between the firm capacity and the forecasted load.

Table 10: Suggested System Maximum Capacity with Increasing Number of Units

	Summer (kW)	Winter (kW)
Potential Firm Capacity	6,535	5,810
Potential Firm Capacity Buffer (2025)	1,472	1,397
Potential Firm Capacity Buffer (2035)	1,418	1,330

It should be noted that in this scenario, there would be very little firm capacity buffer available for economic development in the region. For example, any advancement of mining activity with year-round demand in the area would likely increase capacity requirements to the point that a new diesel plant would likely be required.

4 Cost-Benefit Analysis Assumptions

An economic model for the suggested alternative was developed and includes the following costs:

- Major capital cost of diesel plant replacements;
- Operating maintenance cost (non-fuel);
- Reoccurring minor capital upgrade costs;
- Diesel plant replacements; and
- Fuel costs.

4.1 Major Capital Cost

The upfront capital cost assumed for Alternative 7 is approximately $34.5 million,[15] which is only the 25 kV interconnection cost. The capital cost to construct the regional diesel plant in the year 2030 is $29.4 million.

The following capital upgrades could apply to Alternative 7, but for simplicity and due to the lack of cost estimates, they were not included. The omission of these costs results in a conservative approach when comparing this alternative with Alternative 3a, the proposed least-cost alternative.

- Implementation of a control system capable of managing the operation of the interconnected diesel plants.
- Upgrading diesel plant service conductor, main bus/switchgear, and substation transformers required.
    - Each of these upgrades is expected to cost at least $250,000 and could be significantly higher as diesel plants may not have enough physical space to install switchgear large enough to meet the main bus capacity requirements. There may also be a need to upgrade transformers to a three-phase, pad-mounted unit with on-site backup to meet the transformation capacity requirements; and

[15] 54% of $63.9 million = $34.5 million as outlined in "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021, sch. 1, att. 1, Table 7, at p. 33 and Table 14, at p. 41.

- Upgrades required to maintain adequate voltage regulation or fault levels.
  - Detailed load flow and fault studies have not been completed for this alternative. Additional capital upgrades could be necessary to ensure steady-state or transient voltage criteria are not violated. The quality of power delivered to the customers must not be reduced.

4.2 Operating Maintenance Costs (Non-Fuel)

The operating maintenance costs for Alternative 7 were assumed to be the same as Alternative 2 with all costs associated with Charlottetown removed until the year 2030. After 2030, the operating maintenance costs were assumed to be the same as Alternative 3b. Operating maintenance costs of the distribution interconnection were applied to each year of the full analysis.

No additional operating maintenance costs were included to account for the increased operation of the existing generating units.[16]

4.3 Reoccurring Minor Capital Upgrades

The reoccurring minor capital costs for Alternative 7 were assumed to be the same as Alternative 2 until the year 2030 with the costs associated with a new plant in Charlottetown removed. The reoccurring capital costs of the other three plants were updated to reflect a new overhaul and replacement schedule developed to account for the increase in operating hours on the existing plants up until the year 2030.[17]

4.4 Diesel Plant Replacements

The timing and costs of diesel plant replacements were assumed to be the same as those applied in Alternative 2. A sensitivity analysis is included in Section 5.2.1 to determine the Cumulative Net Present Value ("CPW") of Alternative 7 if diesel plant replacement costs were reduced by 50%. It is noted that maintaining a reliable level of service with such a significant reduction in sustaining capital would be extremely challenging. For the purpose of this investigation, it was assumed that only moderate plant refurbishment would be required for long-term operation.[18]

4.5 Fuel Costs

The fuel costs included in the economic model for Alternative 7 were calculated by assuming that the energy required to power Charlottetown until the year 2030 is generated from the Port Hope Simpson diesel plant. Additional losses were included to account for the power flow from Port Hope Simpson to Charlottetown. Station Service load was assumed to be the same as Alternative 2 with the load at Charlottetown removed. No additional station service losses are modelled at the remaining diesel plants

[16] This assumption skews the analysis in favor of the suggested alternative as in reality there would be a significant increase in the number of operating hours on the diesel units in the three remaining diesel plants in comparison to Alternative 2. This would result in increased operation and maintenance costs at the remaining diesel plants.

[17] This includes advancing the requirement for a replacement of a 500 kW unit from 2027 to 2026 and two additional overhauls in Port Hope Simpson

[18] Based on recent major diesel plant refurbishment project costs (Makkovik), it is not expected that a major refurbishment would cost less than 50% of a diesel plant replacement.

even though the amount of generation from these plants is expected to increase.[19] After 2030, the losses and station service are assumed the same as Alternative 3b.

5 Cost-Benefit Analysis Results

5.1 Base Case Results

The results of the cost-benefit analysis including Alternative 7 are provided in Table 11.

Table 11: CPW Analysis Results (2020–2070) – 50 Year Study ($)[20]

Alternative	CPW	CPW Difference between Alternative and the Least-Cost Alternative
Alternative 3a: Phased Interconnection	153,400,000	0
Alternative 3b: Full Interconnection	155,300,000	1,900,000
Alternative 7: Interconnection with Delayed Regional Diesel Plant (2030)	158,300,000[21]	4,900,000
Alternative 1: Mobile Option	177,400,000	24,000,000
Alternative 2: New Charlottetown Plant	184,700,000	31,200,000

5.2 Sensitivity Analysis Results

Hydro considered two additional sensitivity variations to Alternative 7. They are:

- Reduced diesel plant replacement costs; and
- Delaying the regional diesel plant to 2035.

5.2.1 Reduced Diesel Plant Replacement Cost

If the cost of diesel plant replacements is reduced by 50%, then the results of the cost-benefit analysis are provided in Table 12.

[19] This assumption skews the analysis in favor of the suggested alternative as it is expected that the station service losses at the existing diesel plant would increase due to the increased amount of generation at these plants.
[20] CPW is presented in 2020 dollars.
[21] CPW does not include all capital upgrades required as per Section 4.1.

Table 12: CPW Analysis Results - Sensitivity Analysis (Reduced Diesel Plant Replacement Costs) ($)

Alternative	**CPW**	**CPW Difference between Alternative and the Least-Cost Alternative**
Alternative 3a: Phased Interconnection	151,000,000	0
Alternative 3b: Full Interconnection	152,400,000	1,400,000
Alternative 7: Interconnection with Delayed Regional Diesel Plant (2030)	156,000,000[22]	5,000,000
Alternative 1: Mobile Option	171,600,000	20,600,000
Alternative 2: New Charlottetown Plant	179,500,000	28,500,000

5.2.2 Delaying Regional Diesel Plant until 2035

The following case considers the economic impact of modifying Alternative 7 by extending the life of the Mary's Harbour diesel plant to match the scheduled replacement date of the Port Hope Simpson diesel plant. Under this scenario, the construction of the regional plant would also be delayed until 2035. The results of this analysis are presented in Table 13.

Table 13: CPW Analysis Results - Sensitivity Analysis (Regional Plant Delayed Until 2035) ($)

Alternative	**CPW**	**CPW Difference between Alternative and the Least Cost Alternative**
Alternative 3a: Phased Interconnection	153,400,000	0
Alternative 3b: Full Interconnection	155,300,000	1,900,000
Alternative 7: Interconnection with Delayed Regional Diesel Plant (2035)	161,100,000[23]	7,700,000
Alternative 1:Mobile Option	177,400,000	24,000,000
Alternative 2: New Charlottetown Plant	184,700,000	31,200,000

The results demonstrate that delaying the construction of the regional plant until 2035 increases the CPW of Alternative 7 and the CPW difference in comparison to Alternative 3a. The additional delay triggers the need for 2 additional unit replacements, 11 overhauls, an additional fuel tank inspection, and increased fuel costs between the years 2030 and 2035. The cost of these items exceeds the savings associated with delaying the regional diesel plant and reducing overall operating and maintenance.

6 Conclusion

Based on the contents of this technical note and the analysis presented, it can be concluded that the suggested alternative, Alternative 7, is not the least-cost alternative when compared against the

[22] CPW does not include all capital upgrades required as per Section 4.1.
[23] CPW does not include all capital upgrades required as per Section 4.1.

alternative proposed in Hydro's Long-Term Supply Study (Alternative 3b). This remains the case even if future diesel plant replacement capital costs are reduced by over 50% or if the regional plant is delayed until 2035. As described in Sections 4.1 to 4.5, there is also an appreciable risk of increased system upgrade costs for Alternative 7 that, if included, would further favour Alternative 3b.

Finally, Alternative 7 would not be able to accommodate appreciable economic development in the region until a regional diesel plant is developed. This is of particular importance when considering the mineral deposits in the area.

In summary, Alternative 7 involves a solution that would defer the construction of a new diesel plant in southern Labrador. Through cost-benefit analysis, Hydro has demonstrated that such an approach would result in increased lifecycle costs for customers and would be prohibitive for appreciable near-term load development in the region. On this basis, Hydro recommends Alternative 3a as the preferred alternative.

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1	S. Henderson	Initial Release	2022/03/15

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